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Strategic Participation of Active Citizen Energy Communities in Spot Electricity Markets Using Hybrid Forecast Methodologies

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Abstract: The increasing penetrations of distributed renewable generation lead to the need for Citizen Energy Communities. Citizen Energy Communities may be able to be active market players and solve local imbalances. The liberalization of the electricity sector brought wholesale and retail competition as a natural evolution of electricity markets. In retail competition, retailers and communities compete to sign bilateral contracts with consumers. In wholesale competition, producers, retailers and communities can submit bids to spot markets, where the prices are volatile or sign bilateral contracts, to hedge against spot price volatility. To participate in those markets, communities have to rely on risky consumption forecasts, hours ahead of real-time operation. So, as Balance Responsible Parties they may pay penalties for their real-time imbalances. This paper proposes and tests a new strategic bidding process in spot markets for communities of consumers. The strategic bidding process is composed of a forced forecast methodology for day-ahead and short-run trends for intraday forecasts of consumption. This paper also presents a case study where energy communities submit bids to spot markets to satisfy their members using the strategic bidding process. The results show that bidding at short-term markets leads to lower forecast errors than to long and medium-term markets. Better forecast accuracy leads to higher fulfillment of the community programmed dispatch, resulting in lower imbalances and control reserve needs for the power system balance. Furthermore, by being active market players, energy communities may save around 35% in their electrical energy costs when comparing with retail tariffs.

Keywords: Balance Responsible Parties; Citizen Energy Communities; electricity markets; forecast methodologies; imbalance penalties; strategic bidding

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1. Introduction

The liberalization process brought full competition to the electricity supply industry in both wholesale and retail markets [1]. As a consequence, the market agents have the option to trade electricity in different markets [2]: spots, continuous, derivatives, non-organized, and ancillary services markets.

In spot markets, agents can submit bids to electricity pools based on day-ahead and intraday or real-time marginal auctions. In continuous intraday markets, players can negotiate energy based on the pay-as-bid scheme, i.e., an automatic match of opposite bids [3]. These markets were designed for dispatchable players, i.e., players that can comply with a programmed dispatch, which means that players like consumers and variable generation without storage capacity will have real-time deviations [4,5]. Real-time deviations from the schedules of Balance Responsible Parties (BRPs) have to be balanced at balancing markets. Balancing markets are part of the ancillary services of the system, managed by transmission system operators (TSOs) to guarantee the secure operation of power systems. BRPs with deviations from their schedules may need to pay penalties concerning spot markets. They will receive the down/up balancing prices according to the direction of their deviations [6]. Those penalties are computed considering each country's imbalance settlement (IS) mechanism [7]. In derivatives markets, agents can sign standard financial and physical contracts [8]. For non-standard contracts, agents can negotiate and set the terms and conditions of the private bilateral agreements [9].

Normally, in retail competition, retailers sign private bilateral contracts with clients [10]. Citizen Energy Communities (CECs) are a new market player that competes with retailers for signing private bilateral contracts with end-use consumers [11]. The main problem of retailers is that they usually follow a business-as-usual strategy, proposing high tariffs, equal in each consumer segment [12]. So, being part of a CEC is more economically attractive than signing retail tariffs, but also more demanding by considering the active participation of their members. CECs may be composed of local consumers, prosumers, distributed generation, and storage assets. Considering the global goal of a carbon-neutral society and the increasing penetration of distributed generation, CECs aim to achieve energy sustainability by managing local resources [13]. Against this background, new European legislation supports the active participation of consumers through CECs by providing significant discounts on their grid usage and access costs [14–16]. To satisfy the needs of their members, CECs can enter into the wholesale competition, submitting bids to spot markets, signing private bilateral contracts with producers, and standard contracts on the exchanges or OTC [17,18]. Algarvio [13] presented a review of CECs, as power system alliances that need resource management and coordination.

To avoid future losses, forecasting market prices is one of the aspects that CECs have to consider when participating in wholesale markets. Furthermore, forecasting their energy needs is one of the biggest issues that CECs have to face. The consumption dynamic of members is very dependent on the meteorological conditions, the type of days, and the segment type of consumers [19]. So, minimizing the consumption volatility of members can be a good solution to avoid high forecast errors, which can result in unbalances, and, consequently, in the payment of penalties by CECs. Thus, CECs should have an appropriate trading strategy to mitigate those errors. An adequate short-run strategic bidding on spot markets is crucial to mitigate potential consumption unbalances, since bilateral transactions are usually made in the long run (months prior to real-time consumption). Accordingly, monitoring the real local dispatch with smart meters is a critical aspect of communities with members composed of consumers, prosumers, and distributed generation [20,21]. Furthermore, it enables them to control their net load by using demand response programs, i.e., controlling the local energy production or consumption in case of shortages or excesses of energy [22,23].

Ayón et al. [24] indicated that large and diversified quantities of end-use clients might reduce load forecast errors. Furthermore, they concluded that aggregations of flexible loads are typically beneficial to reduce their forecast errors. Therefore, load aggregations may benefit market players concerning individual loads. Wei et al. [25] presented a complete review of 128 forecast models of energy load. They considered that highly accurate forecasts have a maximum mean absolute percentage error (MAPE) of 10%. Naturally, they concluded that forecasting small-scale loads have larger errors than large-scale loads. Furthermore, they also concluded that the forecast accuracy increase with the time horizon, i.e., long-term (yearly) and medium-term (monthly or quarterly) forecasts have smaller errors than short-term forecasts (from daily to sub-hourly). Naturally, demand is weather-driven, so by analyzing the studied models, the authors concluded that the forecast accuracy increase with the time scale being high to yearly forecasts than to hourly forecasts. However, considering hourly forecasts, the forecast accuracy increases how closer to real-time operation [26]. Koponen et al. presented a review of 12 models to forecast the short-term electrical energy load [27]. They considered six different scenarios to test these models. They concluded that the forecast errors decrease with an increase in the number of aggregated consumers, considering the normalized root mean square error (NRMSE). Furthermore, they indicated that their results do not support the use of specific criteria (such as MAPE or NRMSE) to compare methods. They also concluded that it should be used hybrid methods to compute demand forecasts. Algarvio and Lopes [28] presented a strategic bidding strategy for retailers considering hybrid forecast methodologies in spot day-ahead and intraday markets.

They concluded that the participation of retailers closer to real-time markets improves their forecast accuracy and their return from markets. It also has been concluded that retailers with larger and diversified portfolios have lower forecast errors.

Against this background, this paper focuses on upgrading the strategic bidding process for retailers in wholesale power markets presented in the previous work, considering its adaptation to CECs. It considers a new forecast methodology for the day-ahead market based on forced forecast and adapted the forecast methodology considered for the spot intraday market based on the short-run energy trends of the community, aiming at reducing forecast errors, and, consequently, the unbalances and penalties. Specifically, the purpose of the paper is threefold:

1. To use a model of management of the local members of the community;
2. To develop a strategic bidding process that aims at satisfying the energy needs of the community members, by submitting bids to wholesale markets with the goals of reducing forecast errors, unbalances and penalties, and the total cost of energy when compared to retail tariffs;
3. To develop a case study that tests the strategic bidding process, and compares its results with non-risk retail tariffs. The case study involves a community composed of 312 Portuguese consumers, considering their real consumption data from 2012 extrapolated to 2019, and the real Iberian market of electricity (MIBEL) and Portuguese IS costs from 2019.

The work presented here refines and extends the previous work on CECs composed of consumers [11], their agent-based management [13] and model, bilateral model [18], strategic bidding of retailers [28], and risk management [29,30]. The main novelty of the presented work consists of the equipment of the agent-based model of CECs with a new strategic bidding process that enables them to participate in wholesale electricity markets. Indeed, CECs have already been recognized by European legislation, and some CECs are already active in Portugal [11,14–16]. The main limitation of CECs is that they need to bid at least 1 MW of power to participate in spot markets. Therefore, CECs need to have a relevant weight not to need market intermediates.

The remainder of the paper is structured as follows. Section 2 presents an overview of electricity markets, considering spot, balancing, and IS markets. Section 3 introduces a model for strategic bidding of CECs. Section 4 presents a case study. Finally, concluding remarks are presented in Section 5.

2. Electricity Markets

Active market players have the option to trade electricity in five different markets: spots, continuous, derivatives (forwards, futures, swaps, and options), non-organized (private bilateral contracts), and ancillary services markets. In spot markets, agents can submit bids with a minimum of 1 MW to electricity pools based on day-ahead and intraday or real-time marginal auctions [3].

In Europe, day-ahead markets close at noon (CET time zone) of the day-ahead to real-time operation between 12–37 h before real-time commitment. European markets are coupled and use EUPHEMIA, a marginal pricing common algorithm used to solve power flows between different market zones with the goal of maximizing social welfare [31]. In Europe, it is also possible to trade energy in several intraday auctions a few hours ahead of real-time operation and in the continuous intraday market. In continuous intraday markets, players can negotiate 15 min-ahead of real-time operation based on the pay-as-bid scheme [3]. In derivatives markets, agents can sign standard financial and physical contracts on the exchanges (clearing houses) or over-the-counter (OTC) through electronic trading to reduce risk by hedging against spot price volatility and consumption uncertainty [17]. For non-standard agreements, agents can privately negotiate and set the terms and conditions of the contracts on non-organized markets [9]. These markets were designed for large dispatchable players, i.e., players that can comply with a programmed dispatch and have enough power to participate in these markets, which means that players like retailers, CECs, and variable generation without storage capacity may have real-time deviations [4,5]. Real-time imbalances of BRPs concerning their final programmed dispatch may have to be balanced during real-time operation [6]. TSOs use balancing markets to guarantee the security of power systems by doing a real-time balance of demand and supply of energy. BRPs may have to pay/receive the down/up balancing costs, which normally results in penalties concerning spot markets [7].

2.1. European Balancing Markets

A variation in the kinetic energy, $qkin_t$, caused by different instantaneous powers of the rotating generators, ΔP_t^s, and/or motors, ΔP_t^d, from their defined set-point values in period t, may lead to deviations between supply and demand and cause frequency and/or voltage oscillations, as presented in the power equilibrium equation [32]:

$$\Delta P_t^s - \Delta P_t^d = \frac{dqkin_t}{dt} \tag{1}$$

In Europe, the maximum secure frequency oscillation in relation to the reference is 0.1%, being the maximum allowed oscillation of 0.5%. Frequency oscillations higher than 0.5% can lead to outages and to the division of connected control areas. When the frequency deviations achieve 0.1%, the balancing reserves are automatically activated to mitigate the deviations that originate this oscillation [33,34].

Traditionally, in Europe exist, four different mechanisms to balance power systems [6]:

- Frequency Containment Reserve (FCR);
- automatic-activated Frequency Containment Reserve (aFRR);
- manually-activated Frequency Containment Reserve (mFRR);
- Replacement Reserve (RR).

FCR is the fastest frequency reserve, being the first to be activated to solve frequency disturbances because of incidents or imbalances between production and consumption, which result in a frequency deviation in relation to the 50 Hz European programmed value. It has to be activated in a maximum of 15 s, and the disturbances need to be controlled in a few seconds. Power systems of the continental European synchronous grid have to reserve 3000 MW of their capacity to support FCR.

aFRR has to be activated in a maximum of 30 s and can stay active until a maximum of 15 min, replacing FCR. It also reestablishes the grid frequency to the scheduled value. Considering the programmed size of aFRR (power band), the TSO defines the band needs for every period. ENTSO-E suggests the minimum size of the symmetric power band [33].

mFRR is firstly used to free up and/or support aFRR and then to continue balancing long-term disturbances for long periods. The TSO is responsible for directly activating this reserve, which allows for solving medium and long-term active-power deviations originated by generators, loads, or other grid disturbances.

In the aFRR and mFRR products, TSOs typically define schedules for blocks of 15 min. In the corresponding markets, an auction for every hour of the day (or blocks of various hours) is carried out, and the technically capable generators are allowed to make bids. The auction criterion aims to determine the lowest capacity price (aFRR capacity market) and the lowest energy price (aFRR and mFRR energy markets), based on marginal pricing, pay-as-bid, or other pricing methods.

RRs are activated to solve long-term incidents that cannot be solved with the previous mechanisms. They are normally traded considering bilateral agreements between TSOs and providers. They can be activated in 15 min and can continue active for hours. This mechanism is activated considering the schedules of the programming dispatch agreed upon between TSOs and providers. While the other mechanisms can be directly activated and controlled by TSOs, in this mechanism, TSOs rely on providers to comply with the programmed dispatch.

Balancing reserves are directly traded between TSOs and providers. Providers of upward regulation will receive the up-regulation price of the reserves. On the contrary, providers of downward regulation will pay the down-regulation price. The costs or revenues of balancing markets are passed to BRPs that have deviations or need to be balanced according to the imbalance settlement mechanism. Normally, the prices of upward and downward regulation are higher and lower than spot prices, respectively, which originate the payment of penalties. Otherwise, BRPs that deviate from their schedules can be compensated or do not pay penalties.

In Europe, IS mechanisms strongly differ between countries. The following mechanisms are the most used [7]:

1. Only BRPs that deviate in the dominant balance direction may pay penalties;
2. Only BRPs who need to be balanced in the dominant direction may pay penalties;
3. All BRPs may pay penalties;
4. BRPs directly and equally pay/receive the balancing costs/revenues.

These mechanisms consider that BRPs will only pay for the balanced energy. The reserved capacity that guarantees the power system security is paid in the tariffs of end-use consumers.

The first two mechanisms are discriminatory, since only BRPs that contribute to deviations in the dominant direction may pay penalties. The second is more discriminatory because only BRPs that need to be balanced may pay penalties, but incentive BRPs to auto-regulate their set points, avoiding the payment of penalties. In these mechanisms, BRPs are not compensated, independently of the balancing prices, which may originate an economic surplus to TSOs. However, when the costs of balancing the system in the dominant direction are lower than in the non-dominant direction, TSOs may have an economic deficit. The third mechanism does not originate an economic deficit to TSOs, because all BRPs will pay penalties concerning their deviations. The fourth mechanism considers that all the balancing costs or revenues are passed to BRPs. This mechanism is fairer in the sense TSOs do not have an economic surplus or deficit. However, it does not incentive BRPs to balance themselves because they can be compensated for their imbalances.

Next, are going to be presented the details of the Portuguese balancing and IS markets.

Portuguese Balancing Markets

Portugal and Spain are members of the Iberian Market of Electricity (MIBEL). MIBEL only manages spot, derivatives, and bilateral markets. Ancillary services are independent for each country and managed by their local TSOs. However, some ancillary services can be traded between TSOs. For continuous balancing, Portugal considers the traditional European frequency reserves with the following specifications [6].

FCR is a mandatory and non-remunerated system service for all technically capable generators connected to the grid. They have to reserve 5% of their nominal power in stable conditions to support FCR. Portugal is part of the synchronous grid of continental Europe, contributing with its FCR reserved capacity to the required 3000 MW of positive and negative FCR ready to be activated in continental Europe.

The Portuguese TSO requires an asymmetrical aFRR power band where its up capacity doubles the down capacity. Historically, in Portugal, the aFRR power band is more used for up-regulation than down-regulation. Thus, concerning ENTSO-E suggestions, the Portuguese TSO upscales the up capacity of the aFRR until 60% and downscales its down capacity until 40%. In Portugal, the TSO allows the participation of all technically capable generators in hourly auctions of aFRR capacity. They are remunerated based on the marginal prices of the hourly auction. Generators have to be capable of providing both down-regulation and up-regulation, bidding an up capacity that has to double the down capacity. Due to the lack of competition, in Portugal are the combined cycle gas turbines that participate in aFRR markets, being the price of the energy they provide in aFRR defined by the regulator.

The energy of mFRR is obtained considering an hourly auction-based separate procurement of both upward and downward regulation on marginal markets. The problem with mFRR is that it is based on hourly auctions, so RRs shall be used for balancing long-term frequency deviations. RRs can be activated in 15 min and continue active for long time periods, based on bilateral contracts negotiated between TSOs and the participants.

2.2. Imbalance Settlement Mechanisms

The Portuguese mechanism considers that BRPs have to pay/receive the costs/revenues of all the energy used to balance the system [7]. Therefore, the TSO does not have an economic surplus or deficit concerning the energy used to balance the system. So, the TSO computes a single penalty, p_t^{pen}, and dual pricing, for period, t, considering the following formulations:

$$p_t^{pen} = \frac{\sum_{o=1}^{O}(p_{0,t} - p_{o,t}) \times q_{o,t}}{q_t^{dev}} \tag{2}$$

$$p_t^{up} = p_{0,t} + p_t^{pen} \tag{3}$$

$$p_t^{down} = -(p_{0,t} - p_t^{pen}) \tag{4}$$

where:

(i) $p_{0,t}$ is the spot price of the programmed energy;
(ii) $p_{o,t}$ is the price of the balancing mechanisms o, considering all balancing mechanisms O;
(iii) $q_{o,t}$ is the quantity of energy used by mechanism o to balance the system;
(iv) q_t^{dev} is all BRPs deviated quantity of energy;
(v) p_t^{up} is the upward imbalance price that all BRPs shall receive (if positive);
(vi) p_t^{down} is the downward imbalance price that all BRPs shall pay (if negative).

BRPs with upward deviations receive the sum of the spot price and the penalty. BRPs with downward deviations pay the subtraction of the penalty to the spot price. In the case of a positive penalty, BRPs are compensated because the prices of the ancillary services are lower when compared to spot markets. Otherwise, they are penalized. In the case of positive upward or downward imbalance prices, the TSO has to pay BRPs. Otherwise, are BRPs who pay to the TSO.

The Nordic and Spanish mechanisms compute the balance direction, and only the BRPs that originate those balance needs must directly pay the price of the energy used to balance the system [7,35]. Contrary to the Portuguese mechanism, this mechanism considers double penalty and single pricing, as presented in the following formulations:

$$penalties = \begin{cases} p_t^{up,pen} = 0 & \text{if } \sum_{o=1}^{O} q_{o,t}^{up} < \sum_{o=1}^{O} q_{o,t}^{down} \\ p_t^{up,pen} = min\left[\frac{\sum_{o=1}^{O}(p_{o,t}^{down} - p_{0,t}) \times q_{o,t}^{down}}{\sum_{o=1}^{O} q_{o,t}^{down}}, 0\right] & \text{if } \sum_{o=1}^{O} q_{o,t}^{up} \leq \sum_{o=1}^{O} q_{o,t}^{down} \\ p_t^{down,pen} = 0 & \text{if } \sum_{o=1}^{O} q_{o,t}^{up} > q_{o,t}^{down} \\ p_t^{down,pen} = min\left[\frac{\sum_{o=1}^{O}(p_{0,t} - p_{o,t}^{up}) \times q_{o,t}^{up}}{\sum_{o=1}^{O} q_{o,t}^{up}}, 0\right] & \text{if } \sum_{o=1}^{O} q_{o,t}^{up} \geq \sum_{o=1}^{O} q_{o,t}^{down} \end{cases} \tag{5}$$

$$p_t^{up} = p_{0,t} + p_t^{up,pen} \tag{6}$$

$$p_t^{down} = -(p_{0,t} - p_t^{down,pen}) \tag{7}$$

where:

(i) $p_t^{up,pen}$ is the penalty of upward deviations;
(ii) $p_t^{down,pen}$ is the penalty of downward deviations;
(iii) $q_{o,t}^{up}$ is the quantity of energy used by mechanism o to upward balance;
(iv) $q_{o,t}^{down}$ is the quantity of energy used to downward balance;

Considering this mechanism, an upward penalty exists when the downward balancing needs are higher, penalizing BRPs with up deviation. On the contrary, are BRPs with down deviations who pay penalties when the upward balancing needs are higher. The problem with this mechanism is that only net deviations in the dominant direction are paid. It is an unfair system that highly penalizes the players that have to pay penalties. However, the Portuguese IS also does not incentive BRPs to be balanced.

The imbalance quantity, q_t^{dev}, assigned to a BRP is computed considering the difference between its final programmed dispatch, q_t^{prog}, and its real-time dispatch, q_t, in period T, as follows:

$$q_t^{dev} = q_t - q_t^{prog} = \int_{t=o}^{T} P_t - P_t^{prog} dt \tag{8}$$

where P_t and P_t^{prog} are the instantaneous powers of the final and programmed dispatch, respectively.

The next section presents the strategic bidding process of CECs able to reduce their imbalances.

3. Strategic Bidding in Wholesale Electricity Markets

Considering CECs with predefined members, as consumers or prosumers, they need to satisfy the energy needs of their members. CECs can enter into bilateral agreements to acquire energy with producers, retailers, or other sellers, and/or can submit bids to spot markets if they have the capability to trade the required minimum power. Bilateral contracts are a form of risk hedging against the volatility of spot prices, although they are subject to risk premiums. Normally, buyers of energy get worse prices in bilateral agreements. Thus, their risks are reduced to the consumption uncertainty of their portfolio and, in a smaller part, to the volatility of spot prices, since they could need to fix their energy quantities by submitting bids to spot markets, as the day-ahead market (DAM) and intraday market (IDM). The DAM is used to obtain/sell the need/excess of energy, that is expected not to be physically cleared by the members. Furthermore, each session of the IDM can be used to compensate for the expected short-run imbalances between all acquired and consumed electricity. Next, can be used the intraday continuous market 15-min ahead of a real-time operation to trade some of the close to real-time expected deviations [3]. Furthermore, as BRPs, CECs are responsible for their members' deviations. Thus, if they have imbalances in relation to their programmed dispatch, they could have to be penalized in balancing markets, paying/receiving the unbalanced down/up prices [6,7].

This section presents a process for strategic bidding in wholesale electricity markets, considering that CECs can also consider bilateral agreements to acquire electricity. The process uses different types of data. It uses historical data to forecast the next day's consumption in the DAM based on a forced forecast. It was selected from the database the most recent hour with an hourly consumption, h, according to the type of forecast day ($\mathcal{D}$): weekday ($\mathcal{W}$), Saturday ($\mathcal{S}$), Sunday ($\mathcal{U}$) or holiday ($\mathcal{H}$). Considering the database with the historical daily consumption data, $\mathcal{D} = \{\mathcal{W}, \mathcal{S}, \mathcal{U}, \mathcal{H}\}$, the formulation to obtain the forecast is:

$$\hat{q}_t = q_{t-h}, \forall h \in \mathcal{D} \tag{9}$$

subject to:

$$\min_{q_{t-h}} h, \{h | (\hat{q}_t \wedge q_{t-h}) \in (\mathcal{W} \vee \mathcal{S} \vee \mathcal{U} \vee \mathcal{H})\} \tag{10}$$

For every time period, CECs can have multiple contracts K, so the total quantity of electricity already guaranteed through bilateral contracts, $q_{c,t}$, is used to compute the bids to each period of the DAM, $q_{0,t}$.

$$q_{0,t} = \hat{q}_t - q_{c,t} \tag{11}$$

$$q_{c,t} = \sum_{k=1}^{K} q_{c_k,t} \tag{12}$$

For each intraday session, s, the forecast, $\hat{q}_{s,t}$, uses the most updated consumption information to forecast the consumption of the CEC and submit bids for the required electricity session. The intraday methodology has been adapted from a forecast methodology for retailers [28]. The computed quantity bid to an intraday session, $q_{s,t}$, to submit to every time period, t, of each intraday session, s, considering the short-run forecasts and all acquired electricity through bilateral contracts, $q_{c,t}$, the DAM, $q_{0,h}$ or the previous intraday session(s), $q_{i,t}$.

$$q_{s,t} \; = \; \hat{q}_{s,t} - q_{c,t} - q_{0,t} - \sum_{i=1}^{s-1} q_{i,t} \tag{13}$$

Then, the real-time imbalance, q_t^{dev}, of period t, is computed considering the difference between the real-time consumption of the CEC, q_t, and the final programmed dispatch, q_t^{prog}, respectively:

$$q_t^{dev} \; = \; q_t - q_{c,t} - q_{0,t} - \sum_{s=1}^{S} q_{s,t} = q_t - q_t^{prog} \tag{14}$$

Each time period balance responsibility of the CEC, C_t^{dev}, considering its deviations, q_t^{dev} and the prices of the excess or lack of electricity, in cases of up, P_t^{up}, or down, P_t^{down} deviations, respectively, are computed as follows:

$$\begin{cases} C_t^{dev} = q_t^{dev} P_t^{up}, & \text{for } q_t^{dev} > 0 \\ C_t^{dev} = \left| q_t^{dev} \right| P_t^{down}, & \text{for } q_t^{dev} < 0 \end{cases} \tag{15}$$

Each bilateral contract k has its own price, $p_{c_k,t}$, so, each time period cost, C_t, of the CEC is:

$$C_t = \sum_{k=1}^{K} p_{c_k,t} q_{c_k,t} + p_{0,t} q_{0,t} + \sum_{s=1}^{S} p_{s,t} q_{s,t} - C_t^{dev} \tag{16}$$

To evaluate the performance of the forecast techniques are used two different indicators, MAPE and NRMSE [28]:

$$MAPE = \frac{100\%}{T} \sum_{t=1}^{T} \left| \frac{q_t - \hat{q}_t}{q_t} \right| \tag{17}$$

$$NRMSE = 100\% \frac{\sqrt{\frac{1}{T} \sum_{t=1}^{T} (\hat{q}_t - q_t)^2}}{q_{max}} \tag{18}$$

where q_{max} is the maximum CEC's demand. The value of $\hat{q}_t$, depends on the time horizon of each market forecast, being equal to $q_{0,t} + q_{c,t}$ in the case of day-ahead forecasts and equal to q_t^{prog} in the case of intraday forecasts.

The following section presents a case study to test the strategic bidding process presented in this section when a CEC participates in the markets presented in the previous section.

4. Case Study

This section presents a case study that tests the process of strategic bidding on spot markets, considering a CEC composed of real-world consumers that want to be active market players.

The case study uses real-world data from 312 Portuguese consumers connected to the medium voltage of the transmission grid, representing around 5% of the national demand during the period from 2011 to 2013 [36]. The CEC is composed of 72 residential aggregations, 189 small commercial aggregations, 13 large commercial, 8 industrial, and 32 aggregations of diverse consumer types. They have a peak demand of 446 MW. Therefore, their consumption data from 2012 are extrapolated to 2019.

In 2019 the regulated energy tariff for medium voltage consumers was 111.93 €/MWh. From this tariff, 70.68 €/MWh is from the wholesale price of energy, 5.26 €/MWh is for retail commercialization, and the rest is for grid access and usage [16]. The last parcel includes the General Economic Interest Cost (GEIC), which results from economic incentives for renewable and thermal generation, with a value of 24.70 €/MWh. The Portuguese legislation highly incentives CECs and self-consumption. So, CECs and self-consumption have a discount of 50% in the GEIC, being the discount of CECs with self-consumption of 100%. Thus, CECs may only pay 23.64 €/MWh for grid access plus the wholesale cost of energy of their own trades, instead of the retail tariff (111.93 €/MWh). Against this background, the goal of this section is to test the strategic bidding process of CECs, considering its forecast accuracy and the market outcomes of the CEC, also considering the different IS mechanisms.

Considering the forecast accuracy, the DAM forecasts have a MAPE of 5.32% and a NRMSE of 4.6%. The IDM forecasts have a MAPE of 4.43% and a NRMSE of 3.62%. According to the literature, forecasts with a MAPE lower than 10% are considered highly accurate forecasts [25]. Comparing these results with the forecast accuracy of retailers when these consumers are part of their portfolios can be concluded that only one out of six retailers can obtain lower errors, and only in the IDM forecasts [28]. So, CECs can improve local forecast accuracy, but reducing the portfolios' diversification of retailers may decrease their national demand forecast accuracy. Thus, CECs can be relevant to balance power systems that consider local marginal pricing and balance, as in the USA and Australia. These values prove the strong accuracy of the employed forecast methodology, as can be seen in Figure 1.

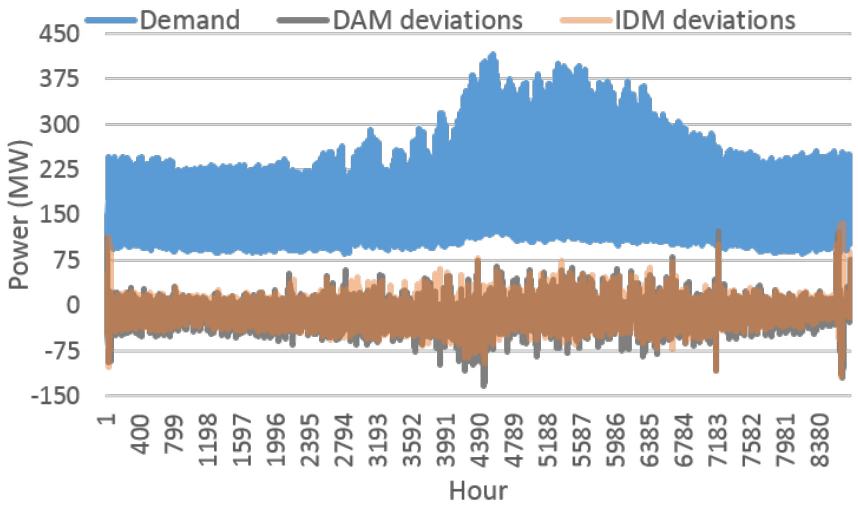

Figure 1. DAM and IDM deviations in relation to real consumption. Brown lines consider the merge between DAM and IDM deviations.

Analysing Figure 1 can be concluded that only a few hours during the year, IDM forecasts are worse than DAM forecasts. Analyzing the figure can be concluded that the CEC demand is higher during summer. This is true because in Portugal, during summer, cooling demand is satisfied by electric air conditioning, while during winter, heating demand is satisfied by natural gas, wood, and electricity. Furthermore, while cooling demand is satisfied during working hours, heating demand is satisfied during the night. Also, while the electrification of commercial buildings is advanced, residential consumers still use other sources of energy for heating demand. Moreover, the majority of the CEC participants are commercial consumers. Against this background, because of the high tourism rates and cooling demand during summer, the summer demand of the CEC is substantially higher than during other seasons. Concerning demand forecasts can be verified that during winter, deviations are higher, mainly at the beginning of January and during December, even considering lower demands when compared to summer. This may occur because of potentially uncertain cold waves that lead commercial consumers to use electrical heating against predictions. It was not detected significant differences in forecast accuracy according to the type of day (weekday, Saturday, Sunday, and holiday).

The main market outcomes of the CEC are presented in Table 1.

Table 1. Average hourly market outputs of the CEC on each market mechanism.

DAM €	IDM €	Portuguese IS €	Nordic IS €
−9579.59	94.05	−300.36	−284.45

From the results, it is possible to conclude that the DAM forecasts are overestimating the CEC consumptions, leading the CEC to sell part of its extra energy in the intraday market. Moreover, the average cost of the imbalances weighs around 3% of the total energy cost.

Table 2 presents the levelized cost of the CEC with energy on wholesale markets.

Table 2. Levelized energy costs of the wholesale market.

Levelized Cost €/MWh	Portuguese IS	Nordic IS
Total	48.89	48.81
IS	1.50	1.42

Analyzing Table 2, it is possible to conclude that consumers may reduce their costs in the energy part of the tariff from 70.68 €/MWh to values below 49.00 €/MWh by being an active market player, besides significant savings in all grid access costs for being part of a CEC. Also, the imbalance costs have a low weight when compared with the energy cost. Consumers may reduce their tariffs from 111.93 €/MWh to 72.53 €/MWh, a reduction of around 35%, by being part of a CEC and active market players. Furthermore, their cost of electrical energy may have a significant reduction in the case they invest in self-consumption.

The proposed strategic bidding already leads to high forecast accuracies and low imbalance costs. So, the CEC has no incentive to invest in storage capacity for self-control of its consumption. However, future power systems with majority penetrations of vRES may need the flexibility of demand players to guarantee the security of supply. Against this background, power systems shall design economically attractive demand response programs to incentive demand-side flexibility. However, in the case considering consumers with self-consumption (prosumers) and/or distributed generation as members of the CEC, the forecast accuracy of the methodology may decrease, which can increase the need for storage solutions or self-regulation of consumption to avoid the payment of high penalties. In the case of considering self-consumption, the CEC will not pay the GEIC costs, reducing their costs with grid access and usage from 28.90 €/MWh to 16.55 €/MWh.

The present study does not consider a change in each consumer behavior, which may be more conscious and active in the case of being part of a community. With increasing levels of distributed generation and local storage, such as solar photovoltaic and electric vehicles, the tendency is to increase the importance of the distribution grid and retire large-scale power plants of the transmission grid. To guarantee the security of supply and security standards in the energy dispatched to/from the transmission grid, local distribution system operators may rely on local consumption flexibility to avoid outages. In power systems with nearly 100% renewable generation, imbalances may be solved locally, avoiding the need for large-scale fossil fuel power plants providing reserves to balancing markets. So, CECs are important as BRPs of current and future power systems. The main problem of CECs is their lack of experience in participating in electricity markets. So, local consumers may be aggregated as a community, obtain bargaining power and then participate in the retail competition to avoid being divided throughout the portfolios of several retailers. However, retailers request substantial market premiums while negotiating long-term bilateral agreements [18]. CECs need to be more active as market players than as part of retailers' portfolios. So, the cost-benefit of being an active/passive consumer of an active/passive CEC may be considered.

In conclusion, it is economically beneficial for passive consumers to be part of an active CEC, considering savings of around 35% concerning retail tariffs, which may increase if consumers have self-consumption and flexibility.

5. Conclusions

This article has presented an overview of the European balancing and imbalance settlement markets. Furthermore, it has presented a strategic bidding process for Citizen Energy Communities (CECs) being active market players, by submitting bids on spot day-ahead (DAM) and intraday markets (IDMs).

The strategic bidding process uses two different hybrid forecast methodologies: a forced forecast for DAM bids and a short-run trend of the expected consumption behavior of the CEC members for IDM bids. The article has also presented a case study to evaluate the CECs' strategic bidding process in spot markets by using real data from the Iberian electricity market (MIBEL) in 2019 and from Portuguese consumers in 2012 but extrapolated for 2019. The model was tested by considering a CEC composed of 312 real medium voltage consumers. Results from the study confirm that large amounts of diversified aggregated demands conduct high forecast accuracies. Furthermore, it confirms that passive consumers economically benefit from being part of CECs, considering tariff incentives and lower wholesale market prices. Indeed, the study proved that consumers save 35% in electrical energy costs by being part of a CEC. Furthermore, their savings can increase if they invest in self-consumption. Moreover, the operation and outcomes of CECs can be improved in the case of having storage assets and flexible consumers, contributing to the local balance of the power system. Indeed, towards a carbon-neutral society, power systems may speed up the replacement of large-scale fossil fuel power plants by renewable distribution (small-scale) and transmission generation (large-scale) if consumers play an active role in the power system balance.

The main issues of CECs being active market players are the volatility of spot prices and the uncertain consumption of their members. They can mitigate the price risk by establishing medium to long-term bilateral agreements in wholesale markets. Furthermore, they can mitigate the quantity risk by signing demand response contracts with members and/or investing in storage solutions.

Future work is intended to study how the strategic bidding model can be adapted to prosumers and distributed generators as members of the CEC, and deal with flexibility considering demand response and storage assets. Moreover, are going to be analyzed the benefits of CECs being active market players or just part of retailers' portfolios.

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Abbreviations

aFRR	automatic-activated Frequency Restoration Reserve
BRP	Balancing Responsible Party
CEC	Citizen Energy Community
CET	Central European Time
DAM	day-ahead market
FCR	Frequency Containment Reserve
GEIC	General Economic Interest Cost
IDM	intraday market
IS	Imbalance Settlement
MIBEL	Iberian market of electricity
MAPE	mean absolute percentage error
mFRR	manually-activated Frequency Restoration Reserve
NRMSE	normalized root mean square error
OTC	over-the-counter
RR	Replacement Reserve
TSO	Transmission System Operator
Indices	
k	contract number
K	number of contracts
$\mathcal{D}$	forecast day
$\mathcal{H}$	holidays set of days
h	hour
i	previous IDM session
o	balancing mechanism
O	number of balancing mechanisms
s	IDM session
S	number of IDM session
$\mathcal{S}$	Saturdays set
t	period
$\mathcal{T}$	number of periods
$\mathcal{U}$	Sundays set
$\mathcal{W}$	weekdays set
Variables	
C	energy cost
P	instantaneous power
P_t^{prog}	programmed power
$p_{0,t}$	DAM price
$p_{c_{ct},t}$	price of bilateral contract
$p_{s,t}$	IDM session price
p_t^{down}	downward imbalance price
p_t^{pen}	penalty price
p_t^{up}	upward imbalance price
q	quantity of energy
$\hat{q}$	forecasted energy
q_t^{dev}	deviated energy
$qkin$	kinetic energy

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